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Evaluation of the Technological Feasibility, and Cost of Selected Control Alternatives Necessary to Meet the Proposed Ohio SO2 Regulations for Industrial Boilers and Processes. Volume II. PPG Industries, Inc. Barberton Plant

GCA Corp, Bedford, Mass. GCA Technology Div.

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Environmental Protection Agency, Chicago, Ill. Air and Hazardous Materials Div.

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Volume II

PPG INDUSTRIES, INC.

BARBERTON PLANT

GCA/TECHNOLOGY DIVISION

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EVALUATION OF THE TECHNOLOGICAL FEASIBILITY, AND COST OF SELECTED CONTROL ALTERNATIVES NECESSARY TO MEET THE PROPOSED OHIO SO_2 REGULATIONS FOR INDUSTRIAL BOILERS AND PROCESSES

FINAL REPORT

Contract No. 68-01-3155
Task Order No. 4

August 1976

Volume II

PPG INDUSTRIES, INC.

BARBERTON PLANT

by

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16. ABSTRACT
This report presents an evaluation by the GCA Corporation, GCA/Technology Division of technological feasibility and cost of complying with the proposed Ohio sulfur dioxide regulation (40 FR 52410, November 10, 1975) at PPG Industries' Barberton plant. The final USEPA Sulfur Dioxide Control Strategy for the State of Ohio Technical Support Documents, Vol. I and II (EPA 905/2-76-002) may be obtained from NTIS.

This plant operates eight coal-fired boilers to provide electric power and process steam for production of chlorine, caustic soda, hydrogen peroxide and silica pigments. After collecting necessary site and process specific data by means of a plant visit, the technical feasibility and cost of flue gas desulfurization by lime, double alkali, and Wellman-Lord scrubbing were evaluated for full capacity (excess electricity sold to a utility) and for roughly 50 percent capacity (enough electricity to maintain normal plant operations).

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ABSTRACT

The results of an evaluation of the technical feasibility, and cost, of complying with the proposed SO_2 emission regulation for fossil-fuel-fired steam generators at PPG Industries Inc. are presented in this report. This site was selected for study as a facility exemplifying the control requirements for large industrial boilers subject to an SO_2 emission limit of 1 to 2 lb $SO_2/10^6$ Btu fuel input. The technical feasibility and cost of lime, limestone, Wellman-Lord and double alkali scrubbing systems were determined. In addition the present cost of compliance coal was evaluated.

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SECTION I

SUMMARY AND CONCLUSIONS

PPG Industries Inc., operates eight boilers to provide electric power and process steam for production of chlorine, caustic soda, hydrogen peroxide and silica pigments. During 1975, 390,000 tons of coal with an average sulfur content of 4.34 percent were burned, producing 32,000 tons of SO_2. The technical feasibility, and cost, of reducing SO_2 emissions to 1.24 $lb/10^6$ Btu (an 84 percent reduction), as would be required by the proposed regulation when the flue gases exit through a single stack, were evaluated.

Flue gas desulfurization by lime, limestone, Wellman-Lord and double alkali scrubbing were considered. These systems are technically feasible commercially availabe and operating in the United States as discussed in the body of this report. Two operating situations were evaluated. First a hypothetical case proposed by PPG in which a system would be installed to control the full capacity of the eight boilers and excess electricity production would be sold to a local utility. In the second case a system would be installed to maintain normal plant operations. This second case would require a system about 50 percent smaller than the first case and is discussed below.

In the second case, the total capital requirements including the battery limit plant, site preparation, retrofit requirement and working capital were $14, $24, $14, and $13 million for the lime, Wellman-Lord, limestone and double alkali systems respectively. Total annualized cost including

cost of capital, depreciation, federal income tax, operating cost, and by-product credit or solid waste disposal cost, ranged from $5.3 to $6.3 million per year. The limestone system by Research-Cottrell and the double alkali system by FMC appeared to be the least expensive systems at $5.3 million per year. This latter cost was equivalent to $0.16/lb sulfur removed or $0.5/10^6 Btu coal burned.

The present incremental cost of compliance coal was estimated to be $0.45 to $0.64/10^6 Btu based on contact with coal companies.

SECTION II

PROCESS AND SITE DESCRIPTION

PPG Industries, Inc., Barberton Plant was visited on 2 April 1976. This facility is located in a mixed residential, commercial, industrial area of Barberton, Ohio, which is in Summit County. The main products of the Barberton Plant are chlorine, caustic soda, hydrogen peroxide and silica pigments. During 1975, 391,019 tons of coal averaging 4.34 percent sulfur were burned to generate the electricity and steam necessary for production of these chemicals. Total sulfur dioxide emissions were 32,000 tons in 1975. The purpose of the plant visit was to collect site and process specific data necessary to determine the technical feasibility and cost of complying with the proposed regulation for control of SO_2 emissions from large coal-fired boilers. Dr. Leo J. Paridon, Technical Manager of the Barberton Plant represented PPG. Boiler design and operating data along with boiler house and site layout diagrams were provided by PPG.

The Barberton Plant boiler facility consists of six spreader stokers (Nos. 3, 6, 7, 8, 9, and 10) which were installed in 1935 and two cyclone boilers (Nos. 11 and 12) which were installed in 1954 and 1961, respectively. PPG plans to repair and refurbish these boilers as often as necessary to keep them operating. On this basis we estimate the remaining life of these units to be 20 years.

Particulate emissions from the cyclone boilers are controlled by electrostatic precipitators located on the side of the boiler house. Each cyclone boiler has its own stack. The flue gas from each spreader stoker passes through a mechanical collector prior to being ducted

a common stack. Summit County is in the Greater Metropolitan Cleveland Air Quality Control Region (AQCR 174) which is a Priority I Region for particulates. The boilers at PPG, with a combined rated capacity of 2710×10^6 Btu/hr input, are limited by the regulations to 0.1 lb/10^6 Btu. The cyclone boilers are in compliance, however, the spreader stokers are emitting about 0.75 lb particulate/10^6 Btu which exceeds the particulate emission limit.

The cyclone boilers are wet bottom units that require coal with an ash fusion temperature below 2550°F.[1] The spreader stokers are dry bottom units. Both the bottom ash and fly ash from the cyclones and spreader stokers are sluiced with water and transported to a solids settling tank. The clarified water effluent from the separating tank is discharged and the thickened solids are shipped one mile by rail to a plant where they are used as an asphalt additive.

Pertinent design and operating data for the boilers at PPG are presented in Table 1. At the present time both cyclones are operating full time (24 hours/day; 336 days/year) while only one of the stokers is operating on an intermittent basis. Based on monthly averages, Table 2 presents coal sulfur and ash contents, heating value and consumption rates for the years 1974 and 1975. In the future PPG may sell electric power to a local utility in which case a FGD system capable of handling the full plant capacity would be required. However, if electric power is not sold then a system designed to clean only the flue gas volume equivalent to operation of the two cyclones and one stoker would be adequate. This latter flue gas volume might be generated by different combinations of stokers and cyclones requiring extensive ducting.

PPG buys their coal by spot purchases from open pit mines in the New Philadelphia, Tuscarawas County area which is located about 60 to 100 miles from their plant. The coal costs approximately $21/ton which includes delivery by truck,

Table 1. PPG INDUSTRIES BOILER DESIGN AND OPERATING DATA

	Spreader stokers						Cyclones	
	No. 3	No. 6	No. 7	No. 8	No. 9	No. 10	No. 11	No. 12
Rated capacity,								
10^6 Btu/hr input	258	258	258	258	258	258	457	705
lb coal/hr[a]	23,050	23,050	23,050	23,050	23,050	23,050	40,850	63,000
Normal operating rate,								
10^6 Btu/hr input	179	179	179	179	179	179	457	635
lb coal/hr[a]	16,000	16,000	16,000	16,000	16,000	16,000	40,850	56,750
Stack gas temperature, °F	470	470	470	470	470	470	325	325
Stack gas flow at rated capacity, scfm	71,280	71,280	71,280	71,280	71,280	71,280	106,710	175,800
Stack gas flow at normal operating rate, scfm	49,450	49,540	49,540	49,450	49,450	49,540	106,710	158,700
Excess air, percent	35 - 70	35 - 70	35 - 70	35 - 70	35 - 70	35 - 70	15 - 35	15 - 35
SO_2 concentration in stack gas, ppm[a]	2,870	2,870	2,870	2,870	2,870	2,870	3,395	3,180
SO_2 emission rate,[a] lb $SO_2/10^6$ Btu input	7.68	7.68	7.68	7.68	7.68	7.68	7.68	7.68

[a]These values were calculated using the average coal sulfur content and/or heating value for 1975 and the assumption that 100 percent of the sulfur in the coal is converted to SO_2.

Table 2. COAL DATA FOR 1974 AND 1975 BASED ON MONTHLY AVERAGES

	1974	1975
Sulfur content, percent		
Average	4.9	4.3
Range	4.3 - 5.8	3.3 - 5.1
Ash content, percent		
Average	15.7	11.3
Range	13.0 - 18.6	7.8 - 14.7
Heating value, Btu/lb		
Average	10,900	11,192
Range	10,525 - 11,515	10,634 - 12,077
Annual consumption, tons/yr	485,012	391,019

According to the proposed regulation[2] S52.1881(b)(3), the allowable SO_2 emission rate from fossil fuel fired steam generators in Summit County is given by:

$$E = 16.71\ Q_m^{-0.329}$$

where E = allowable SO_2 emission rate, $lb/10^6$ Btu

Q_m = the total rated capacity (heat input) of all boilers venting through a common stack, 10^6 Btu/hr.

During 1975, the average sulfur content and heating value of the coal combusted at PPG were 4.3 percent and 11,192 Btu/lb, respectively. Assuming 100 percent of the sulfur in the coal is converted to SO_2, this corresponds to a 1975 emission rate of 7.68 lb $SO_2/10^6$ Btu input. The six spreader stokers which vent through a common stack have a combined rated capacity of 1548 x 10^6 Btu/hr input while the two cyclone boilers which vent through separate stcks have rated capacities of 457 and 705 x 10^6 Btu/hr input. According to the proposed regulations, the allowable SO_2 emission rates are 1.49 lb $SO_2/10^6$ Btu input for the group of six stoker-fired boilers, 2.23 lb $SO_2/10^6$ Btu input for the small cyclone boiler and 1.93 lb $SO_2/10^6$ Btu input for the large cyclone boiler. To meet these limits, 1975 emissions would need to be reduced 81 percent, 71 percent and 75 percent for the stoker-fired boilers and the two cyclone boilers, respectively. If an SO_2 emission control device were installed, the desulfurized flue gas would be vented out a single stack. Since the combined rated capacity of the boilers at PPG is 2710 x 10^6 Btu/hr input, venting the total flue gas through a single stack would appear to require that the emission rate be limited to 1.24 lb $SO_2/10^6$ Btu. This would correspond to an SO_2 removal efficiency of 84 percent.

A schematic of the PPG boiler site is presented in Figure 1. As illustrated by this figure, there are over 30,000 square feet of available ope

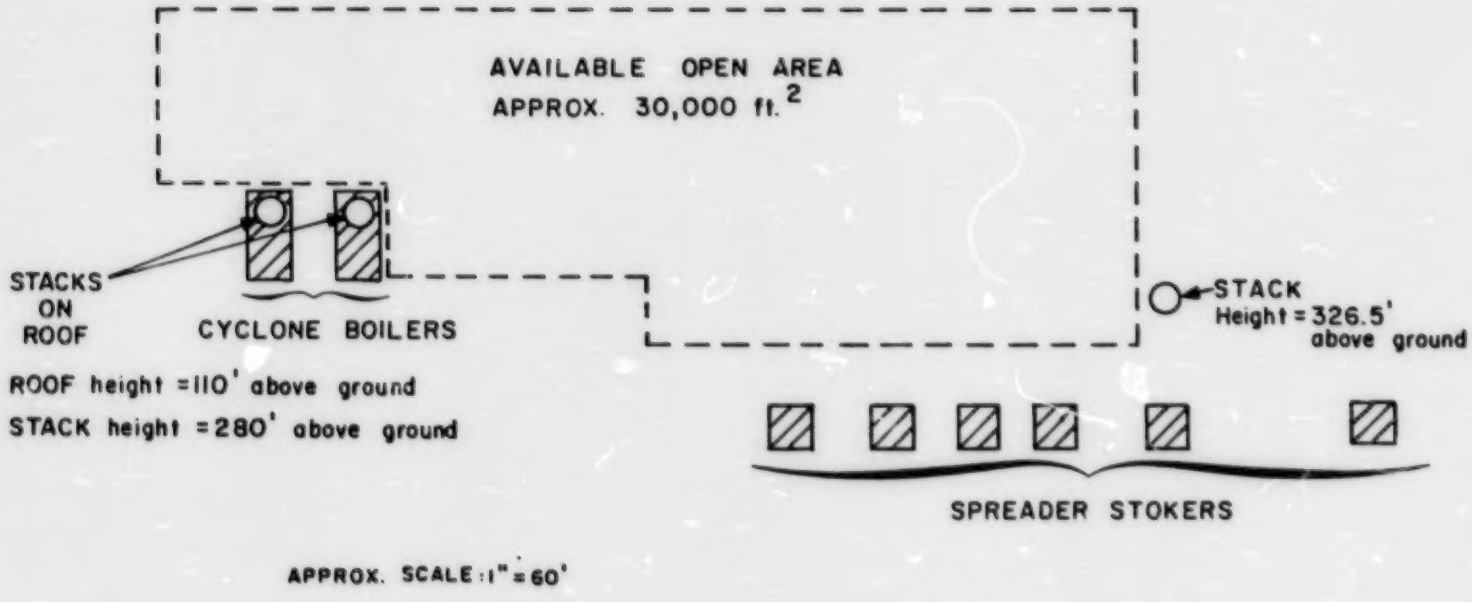


Figure 1. PPG boiler site

area adjacent to the stoker and cyclone boilers that could serve as a site for a flue gas desulfurization system. Retrofitting a desulfurization system to the spreader stokers should not present any unusual problems, but retrofitting the cyclone boilers would be more difficult due to the elevation, clearances and the potential of disturbing the flow distribution through the electrostatic precipitators. A vertical diagram of one of the cyclone boilers is presented in Figure 2. The other cyclone boiler is very similar.

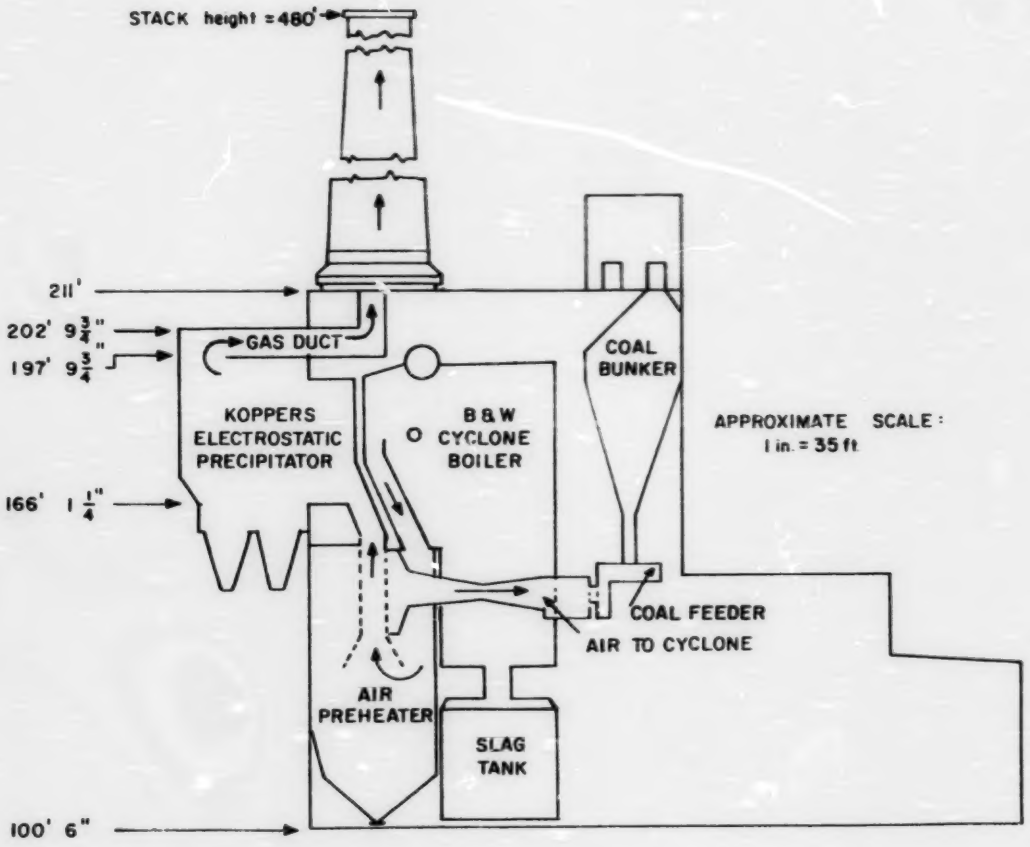


Figure 2. Vertical diagram of PPG cyclone boiler

SECTION III

SO_2 CONTROL TECHNOLOGY FOR COAL-FIRED BOILERS

FLUE GAS DESULFURIZATION SYSTEMS

Based on our review of over a dozen flue gas desulfurization systems the following SO_2 scrubber systems were selected for evaluation of their potential applicability to coal-fired industrial boilers in the State of Ohio:

1. Lime (CaO) and limestone ($CaCO_3$)
2. Double alkali (NaOH/CaO)
3. Magnesium oxide (MgO)
4. Wellman-Lord (Na_2SO_3)

Selection was based primarily on full scale operating experience. The SO_2 removal efficiencies that have been demonstrated by these flue gas desulfurization systems are high enough to put the coal-fired boilers considered in this study well in compliance with the lowest proposed SO_2 emission regulations in the State of Ohio.

Lime and Limestone Scrubber Systems

Combustion Engineering,* Research Cottrell+ and many other companies commercially manufacture lime and limestone scrubbing systems. In these systems, lime or limestone reacts with SO_2 and SO_3 in the flue

*C-E Power Systems, Combustion Engineering, Inc., 1000 Prospect Hill Rd., Windsor, Conn.

+Research Cottrell, P. O. Box 750, Bound Brook, N. J.

gas to form calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$). The Combustion Engineering system introduces the additive, a slurry of pulverized limestone or slaked lime, directly into the scrubber. Recirculation pumps convey the scrubbing solution from the scrubber bottom to underbed spray nozzles. The incoming gas, laden with dust and SO_2, contacts the sprayed slurry and continues to the marble beds which increase the gas-liquid contact. The solution then drains to the scrubber bottom where the chemical reaction is completed and solids are precipitated. A bleed line provides for solids removal to a clarifier or pond. After the solids are separated the clarified water can be recirculated. The clean flue gas passes through a mist eliminator in order to remove moisture and then may be reheated in order to protect the fan and reduce the visibility of the stack plume.[3] A schematic diagram of the C-E lime/limestone scrubber system is presented in Figure 3.

Research-Cottrell offers both a limestone and a lime (Bahco) scrubber system. The limestone scrubber system consists of two stages (see Figure 4). In the first stage, a flooded disc wet scrubber removes fly ash and since a limestone slurry is used to control the pH at this stage, approximately 20 percent of the SO_2 in the flue gas is removed as well. This first stage also acts as a quencher, saturating the gas to a temperature of 125°F. A controlled amount of ash-laden slurry discharges from this first stage to a holding tank for final disposal on an intermittent basis. In the second stage, the flue gas passes up through the packing of the absorber tower, where the limestone slurry circulates. The corrugated polypropylene packing has a large surface area, designed to insure maximum contact between the SO_2 and the limestone slurry. The spent slurry, which includes unreacted limestone, flows into an absorber tank, where salts precipitate out. The reusable slurry, augmented by additional limestone and makeup water, then recirculates through the system. A controlled amount of the slurry is bled to the wet scrubber stage for pH control. After

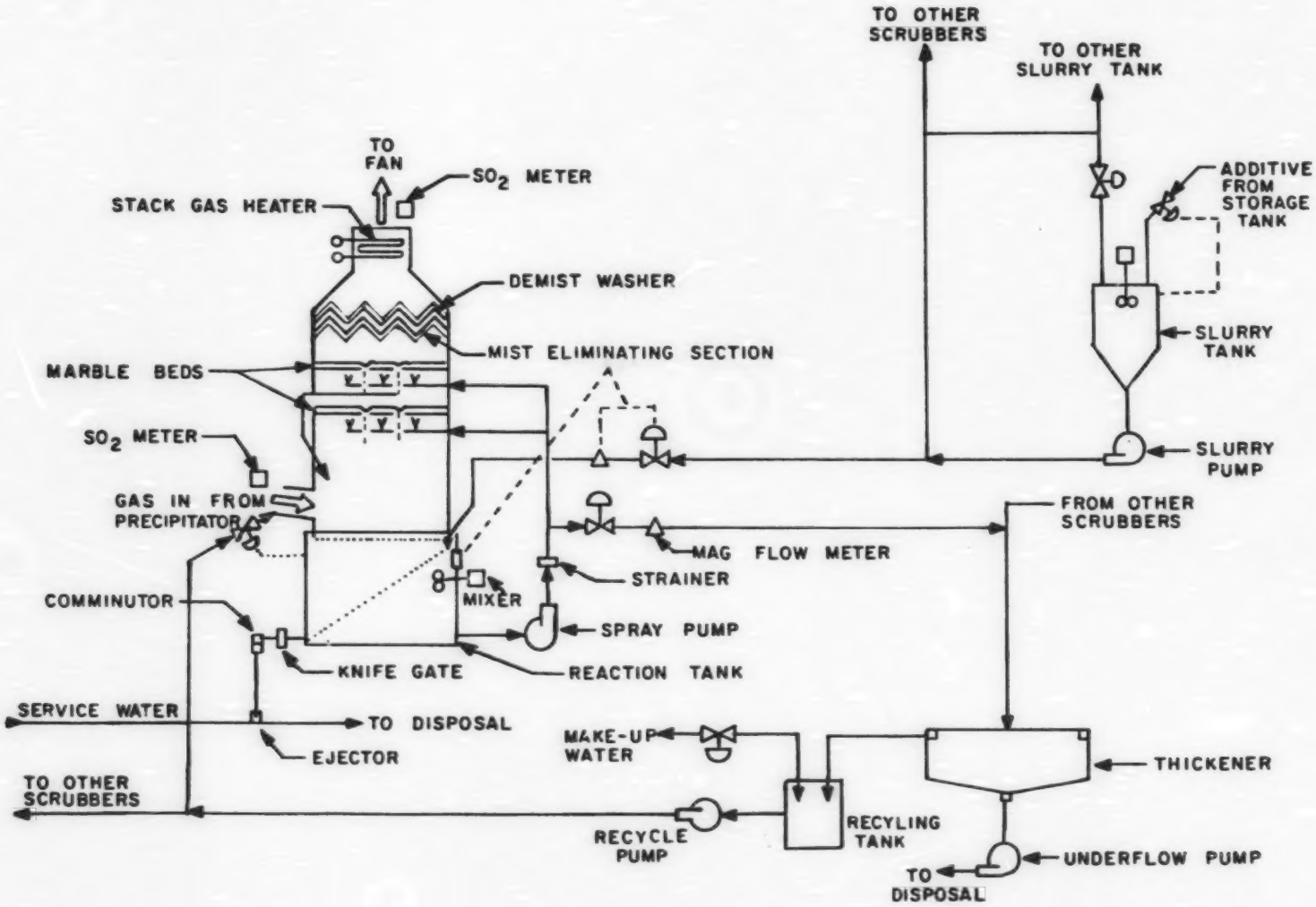


Figure 3. C-E lime/limestone scrubber system[4]

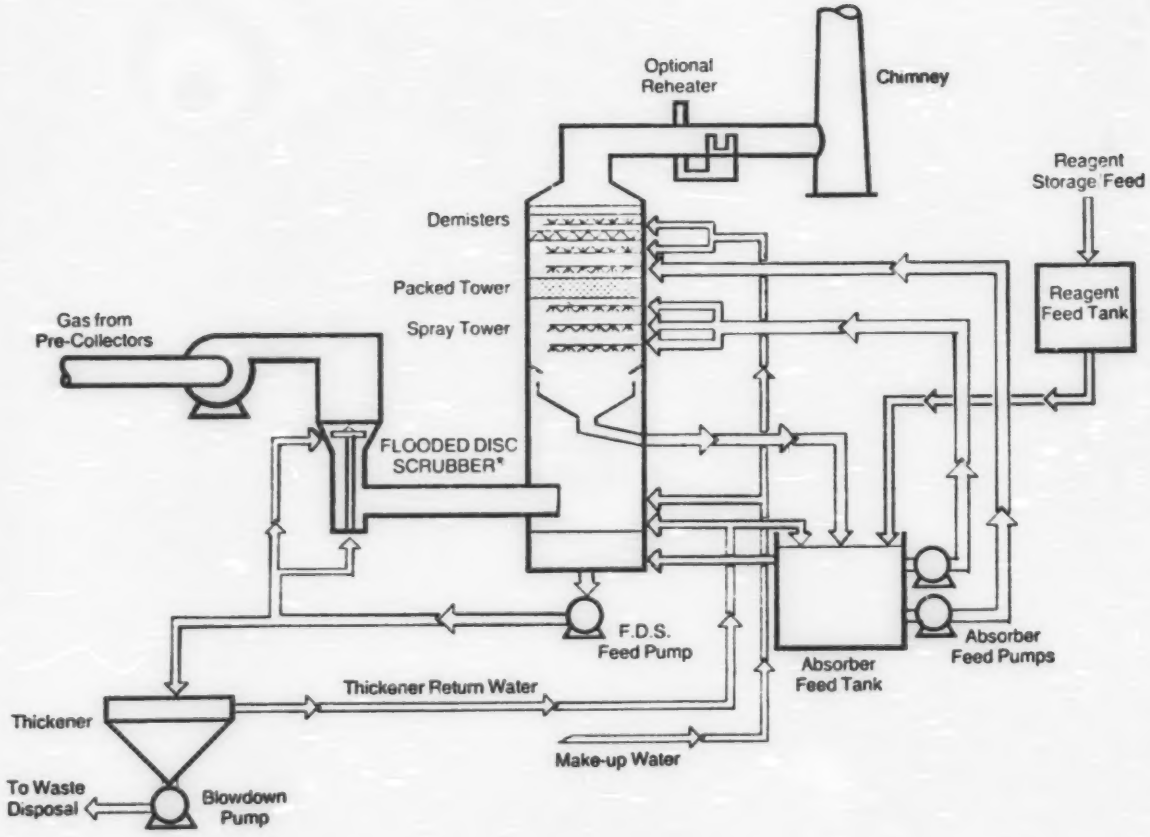


Figure 4. R-C limestone scrubber system[6]

the absorber tower, the flue gas passes through mechanical mist eliminators and then a reheater. Reheating the flue gas prevents stack corrosion, avoids acid rain around the plant, and improves plume buoyancy.[5]

The Research-Cottrell lime (Bahco) scrubbing system (see Figure 5) consists of a two stage venturi. At the bottom of the column, flue gas is directed down against the surface of a milk of lime slurry. The high velocity gas-liquid contact produces a vigorous cascade of droplets that carry up into the first scrubber stage for turbulent mixing with the flue gas. Above the first venturi, droplets are separated in an inertial collector while the gas continues up to a second stage. Here the gas-liquid contact process is repeated. A mist eliminator above the second stage removes liquid droplets before the gas is reheated and/or vented to the stack. Separated liquids from both stages of the venturi return to the lower impingement zone. A fraction of this return flow is continuously removed for disposal, usually to a thickener. Clarified liquid is returned to the lime dissolving tank to minimize makeup requirements.[7]

Limestone and lime based scrubbing is the oldest and most widely used commercially available flue gas desulfurization technology. As shown in Table 3, limestone scrubbing units applied to coal-fired boilers have been operating since 1968. As would be expected, the availability of the early units was not good. However, since then the technology has improved due to operating and design experience. As a result, the availability of lime and limestone scrubbing systems installed since 1973 has thus far ranged from 58 to 90 percent, averaging over the operating life of the systems.[8,9] It is important to note that specific units such as the Cholla No. 1 have been able to achieve availability of 90 to 100 percent over the last 2 years.[8]

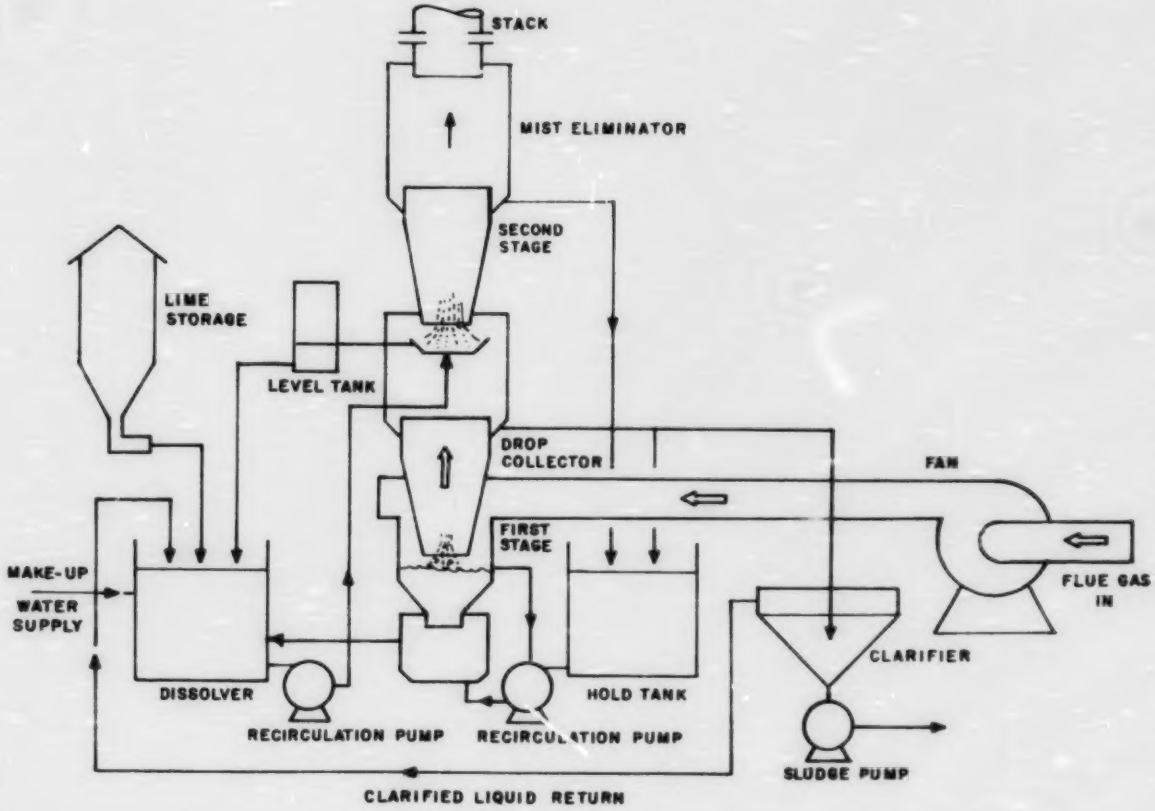


Figure 5. R-C lime (Bahco) scrubber system[7]

Table 3. STATUS OF LIME AND LIMESTONE FLUE GAS DESULFURIZATION SYSTEMS AS OF 5/76/[8,9]

Operational systems					
Utility company power station	Size of FGD unit, MW[a]	Vendor/process	Fuel characteristics	Startup date, mo/yr	Availability, %
Arizona Public Service Cholla No. 1	115	Research Cottrell/ limestone scrubbing	Coal - 0.44-1 percent sulfur	10/73	88
Commonwealth Edison Will County No. 1	167	Babcock & Wilcox/ limestone scrubbing	Coal - 9463 Btu, 2.1 percent sulfur	2/72	26
Dairyland Power Coop Alma Station	80	Foster Wheeler/ lime injection	Coal - 3.0 - 3.5 percent sulfur	6/71	-
Duquesne Light Elrama	510	Chemico/ lime scrubbing	Coal - 1.0 - 2.8 percent sulfur	10/75	-
Duquesne Light Phillips	410	Chemico/ lime scrubbing	Coal - 1.0 - 2.8 percent sulfur	7/73	73
Kansas City Power & Light Hawthorn No. 3	140	Combustion Engineering/ limestone injection & wet scrub	Coal - 0.6 - 3.0 percent sulfur	11/72	36
Kansas City Power & Light La Cygne No. 1	820	Babcock & Wilcox/ limestone scrubbing	Coal - 5.2 percent sulfur	2/73	85
Kansas City Power & Light Hawthorn No. 4	100	Combustion Engineering limestone injection & wet scrub	Coal - 0.6 - 3.0 percent sulfur	8/72	64
Kansas Power & Light Lawrence No. 4	125	Combustion Engineering/ limestone injection & wet scrub	Coal - 3.5 percent sulfur	12/68	-
Kansas Power & Light Lawrence No. 5	400	Combustion Engineering limestone injection & wet scrub	Coal - 0.5 percent sulfur	11/71	-
Kentucky Utilities Green River - Units 1 & 2	64	American Air Filter/ lime scrubbing	Coal - 3.8 percent sulfur	10/75	-
Louisville Gas & Electric Paddys Run No. 6	65	Combustion Engineering/ lime scrubbing	Coal - 3.5 - 4.0 percent sulfur	4/73	58
Montana Power Co. Colstrip No. 1	360	Combustion Equip. Associates/ lime scrubbing	Coal - 0.8 percent sulfur	10/75	-
Rickenbacker AFB Rickenbacker	42	Research Cottrell/ lime scrubbing	Coal - 3.6 percent sulfur	3/76	90
Pennsylvania Power Co. Bruce Mansfield No. 1	835	Chemico/ lime scrubbing	Coal - 4.3 percent sulfur	10/75	8
Public Service Co. of Colorado - Valmont No. 5	50	Universal Oil Products/ limestone scrubbing	Coal - 0.72 percent sulfur	1/75	-
Southern California Edison Mohave No. 1A	170	Universal Oil Products/ limestone scrubbing	Coal - 0.5 - 0.8 percent sulfur	11/74	62
Tennessee Valley Authority Shawnee No. 10	30	Tennessee Valley Authority/ lime/limestone scrubbing	Coal - 2.9 percent sulfur	4/72	-
Northern States Power Co. Sherburne No. 1	680	Combustion Engineering/ limestone scrubbing	Coal - 0.8 percent sulfur	3/76	-
Arizona Public Service Four Corners No. 5A	160	SCE/lime scrubbing	Coal - 0.7 percent sulfur	2/76	-

[a]One MW is approximately equivalent to 10 x 10^6 Btu/hr fuel input and 2200 scfm flue gas.

Table 3 (continued). STATUS OF LIME AND LIMESTONE FLUE GAS DESULFURIZATION SYSTEMS AS OF 5/76[8,9]

Systems under construction

Utility company power station	Size of FGD unit, MW	Vendor/process	Fuel characteristics	Startup date, mo/yr	Availability, %
Central Illinois Light Co. Duck Creek No. 1	100	Riley Stoker/Environeering/ limestone scrubbing	Coal - 2.5 - 3.0 percent sulfur	6/76	-
Columbus & Southern Ohio Elec. - Conesville No. 5	400	Universal Oil Products/ lime scrubbing	Coal - 4.5 - 4.9 percent sulfur	6/76	-
Detroit Edison St. Clair No. 6	180	Peabody Engineering/ limestone scrubbing	Coal - 3.7 percent sulfur	5/76	-
Indianapolis Power & Light Co. - Petersburg No. 3	530	Universal Oil Products/ limestone scrubbing	Coal - 3.0 - 3.5 percent sulfur	9/77	-
Louisville Gas & Electric Cane Run No. 4	178	American Air Filter/ lime scrubbing	Coal - 3.5 - 4.05 percent sulfur	6/76	-
Louisville Gas & Electric Can Run No. 5	183	Combustion Engineering/ lime scrubbing	Coal - 3.5 - 4.05 percent sulfur	12/77	-
Louisville Gas & Electric Mill Creek No. 3	425	American Air Filter/ lime scrubbing	Coal - 3.5 - 4.0 percent sulfur	7/77	-
Minnkota Power Cooperative Milton R. Young No. 2	450	Combustion Equip. Associates/ limestone scrubbing	Lignite - 6,500 Btu, 0.7 percent S	8/77	-
Montana Power Co. Colstrip No. 2	360	Combustion Equip. Associates/ lime scrubbing	Coal - 0.8 percent sulfur	7/76	-
Northern States Power Co. Sherburne No. 2	680	Combustion Engineering/ limestone scrubbing	Coal - 0.8 percent sulfur	5/77	-
Pennsylvania Power Co. Bruce Mansfield No. 2	835	Chemico/ lime scrubbing	Coal - 4.3 percent sulfur	4/77	-
Springfield City Utilities Southwest No. 1	200	Universal Oil Products/ limestone scrubbing	Coal - 3.5 percent sulfur	8/76	-
Tennessee Valley Authority Widows Creek No. 8	550	Tennessee Valley Authority/ limestone scrubbing	Coal - 3.7 percent sulfur	2/77	-
Texas Utilities Co. Martin Lake No. 1	793	Research Cottrell/ limestone scrubbing	Coal - 1.0 percent sulfur	1/77	-
Texas Utilities Co. Martin Lake No. 2	793	Research Cottrell/ limestone scrubbing	Coal - 1.0 percent sulfur	10/77	-
Utah Power & Light Co. Huntington No. 1	415	Chemico/ lime scrubbing	Coal - 0.5 percent sulfur	6/77	-

Table 3 (continued). STATUS OF LIME AND LIMESTONE FLUE GAS DESULFURIZATION SYSTEMS AS OF 5/76[8,9]

Contracts awarded - engineering design / use of development

Utility company power station	Size of FGD unit, MW	Vendor/process	Fuel characteristics	Startup date, mo/yr	Availability, %
Columbus & Southern Ohio Elec. - Conesville No. 6	400	Universal Oil Products/ lime scrubbing	Coal - 4.5 - 4.9 percent sulfur	1/78	-
Arizona Public Service Cholla No. 2	250	Research Cottrell/ limestone scrubbing	Coal - 0.44 - 1 percent sulfur	6/77	-
Alabama Electric Coop Tombigbee No. 2	225	Peabody Engineering/ limestone scrubbing	Coal - 0.8 - 1.5 percent sulfur	3/78	-
Alabama Electric Coop Tombigbee No. 3	225	Peabody Engineering/ limestone scrubbing	Coal - 0.8 - 1.5 percent sulfur	3/79	-
S. Mississippi Elec. PWR Assoc. - R.D. Morrow No. 2	180	Riley Stoker/Environeering/ limestone scrubbing	Coal - 1 percent sulfur	6/78	-
S. Mississippi Elec. PWR Assoc. - R.D. Morrow No. 1	180	Riley Stoker/Environeering/ limestone scrubbing	Coal - 1 percent sulfur	11/77	-
Arizona Electric Power Coop Apache No. 2	200	Research Cottrell/ limestone scrubbing	Coal - 0.5 - 0.8 percent sulfur	6/79	-
Arizona Electric Power Coop Apache No. 3	205	Research Cottrell/ limestone scrubbing	Coal - 0.5 - 0.8 percent sulfur	6/79	-
S. Carolina Pub Serv Authority - Winyah No. 2	140	Babcock & Wilcox/ limestone scrubbing	Coal - 1.0 percent sulfur	5/77	-
Brazos Electric Power Coop G & T Cooperative Project No. 1	400	Babcock & Wilcox/ limestone scrubbing	Coal - 1.67 percent sulfur	12/79	-
Commonwealth Edison Powerton No. 51	425	Universal Oil Products/ limestone scrubbing	Coal - 3.6 percent sulfur	12/79	-
Allegheny Power System Pleasants No. 1	625	Babcock & Wilcox/ lime scrubbing	Coal - 2.0 - 5.0 percent sulfur	3/79	-
Allegheny Power System Pleasants No. 2	625	Babcock & Wilcox/ lime scrubbing	Coal - 2.0 - 5.0 percent sulfur	3/80	-
Kansas Power & Light Jeffery No. 2	680	Combustion Engineering/ limestone scrubbing	Coal - 0.32 percent sulfur	6/79	-
Louisville Gas & Electric Mill Creek No. 4	425	American Air Filter/ lime scrubbing	Coal - 3.5 - 4.0 percent sulfur	7/79	-
Pennsylvania Power Co. Bruce Mansfield No. 3	835	Pullman Kellogg/ limestone scrubbing	Coal - 4.3 percent sulfur	4/79	-
Kansas Power & Light Jeffery No. 1	680	Combustion Engineering/ limestone scrubbing	Coal - 0.32 percent sulfur	6/78	-
Utah Power & Light Co. Emery No. 1	400	Chemico/ lime scrubbing	Coal - 0.5 percent sulfur	6/78	-
Southern Illinois Power Coop Southern Illinois Power Pt. 4	184	Babcock & Wilcox/ limestone scrubbing	Coal -	1/78	-

Tables 4, 5, and 6 present pertinent design and operating data for the limestone and lime based scrubbing systems discussed in this section.

Double Alkali Scrubber Systems

FMC Corporation* commercially offers double alkali scrubber systems. The process consists of a sodium-based scrubbing loop in which the sulfur dioxide in flue gas is collected according to the following reactions:

$$Na_2CO_3 + H_2O \rightarrow 2NaOH + CO_2$$

$$2NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$$

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

and subsequently precipitated with calcium in a separate loop according to the reaction:

$$2NaHSO_3 + Ca(OH)_2 \rightarrow CaSO_3 + Na_2SO_3 + 2H_2O$$

This system was developed primarily to alleviate scaling problems initially encountered with lime/limestone systems. The spent scrubber solution which is primarily composed of sodium bisulfite ($NaHSO_3$) is pumped to a lime reactor where it mixed with slaked lime. In the reactor, sodium bisulfite is converted to sodium sulfite (Na_2SO_3) and calcium sulfite ($CaSO_3$) is precipitated out, thickened and put through a rotary drum vacuum filter. The sodium sulfite solution is then recirculated back to the scrubber. Due to oxygen in the flue gas, a portion of the sodium sulfite is oxidized to become sodium sulfate. These chemical losses are offset with makeup soda ash.[14] A schematic of FMC's double alkali

*FMC Corporation, Environmental Equipment Division, 21 Charles Street, Westport, Conn.

Table 4. COMBUSTION ENGINEERING LIMESTONE/LIME SCRUBBING SYSTEM[10,11]

Smallest system capacity commercially available (scfm)	130,000
Overall pressure drop through system (in H_2O)	10 - 16
Turndown ratio of system	3:1
SO_2 removal efficiency, percent	75 - 90
Raw materials	Limestone or lime
By-products	None
Wastes,[a] lb waste/lb SO_2 removed	6.9 lb sludge cake from clarifier containing 35 percent solids ($CaSO_3$, $CaSO_4$ and unreacted limestone) and 65 percent water
Maintenance presented some problems	Scale and solids buildup and corrosion have presented some problems which have been alleviated by modifying the system design.
Development status (see Table 3)	Operational systems 140 Mw 0.6 - 3.0 % S coal 140 Mw 0.6 - 3.0 % S coal 125 Mw 3.5 % S coal 400 Mw 0.5 % S coal 65 Mw 3.5 - 4.0 % S coal 360 Mw 0.8 % S coal Systems under construction 183 Mw 3.5 - 4.05 % S coal 680 Mw 0.8 % S coal 680 Mw 0.8 % S coal

[a]Does not include the fly ash that would be removed.

Table 5. RESEARCH-COTTRELL LIMESTONE SCRUBBING SYSTEM[6,8,9,12]

Smallest system capacity commercially available (scfm)	130,000
Overall pressure drop through system (in H_2O)	10 - 20
Turndown ratio of system	4:1[a]
SO_2 removal efficiency, percent	85 - 90
Raw materials	Limestone (95 percent $CaCO_3$)
By-products	None
Wastes[b] lb waste/lb SO_2 removed	6.9 lb sludge cake from clarifier containing 35 percent solids ($CaSO_3$, $CaSO_4$ and unreacted limestone) and 65 percent water
Maintenance	Scale and solids buildup and corrosion have presented some problems which have been alleviated by modifying the system design.
Development status (see Table 3)	Operational systems 115 Mw 0.44 - 1.0 % S coal Systems under construction or in the design stage of development 250 Mw 0.44 - 1.0 % S coal 793 Mw 1.0 % S coal 793 Mw 1.0 % S coal

[a]Any turndown ratio may be accomodated by the addition of makeup air.

[b]Does not include the fly ash that would be removed.

Table 6. RESEARCH-COTTRELL LIME (BAHCO) SCRUBBING SYSTEM[13]

Samllest system capacity commercially available (scfm)	20,000
Overall pressure drop through system (in H_2O)	16 - 26
Turndown ratio of system	1.5: 1[a]
SO_2 removal efficiency, percent	90 - 99
Raw materials	Lime
By-products	None
Wastes[b] lb waste/lb SO_2 removed	6.1 lb cake containing 35 percent solids ($CaSO_3$ and $CaSO_4$) and 65 percent water
Maintenance	Scaling and solids deposition appear to be less severe than for limestone based scrubbing systems. Corrosion can be minimized by properly designing the system.
Development status (see Table 3)	Operational systems 42 Mw 3.6 % S coal

[a]Any turndown ratio may be accomodated by the addition of makeup air.

[b]Does not include the fly ash that would be removed.

scrubber system is presented in Figure 6. Table 7 presents pertinent design and operating data for the FMC double alkali scrubbing system.

Magnesium Oxide Scrubber (MgO)

The Chemical Construction Company (Chemico) commercially offers this system. In this system MgO absorbs the SO_2 and SO_3 in flue gas to form $MgSO_3$ and $MgSO_4$ which are thermally regenerated by a calcining system. The SO_2 driven off in the regeneration step can be used to form either sulfuric acid or elemental sulfur.[16] Although Battelle recently reported that this system could be economically applied to small industrial boilers,[17] other sources report that the economics of this process do not look positive for the production of less than 3 to 4 hundred tons of H_2SO_4 per day.[18] This would roughly correspond to a 600 Mw boiler operating at capacity, burning 3 percent sulfur coal. Since the boiler installations being evaluated in this study are considerably less than 600 Mw, the magnesium oxide system will not be given further consideration due to unattractive economics.

Wellman-Lord SO_2 Recovery Process

The Wellman-Lord regenerative SO_2 process is commercially marketed by Davy Powergas.* In this process flue gas is contacted counter-currently with a sodium sulfite (Na_2SO_3) solution in a trayed or packed absorber. SO_2 in the flue gas combines chemically with sodium sulfite to form sodium bisulfite ($NaHSO_3$). Due to oxygen in the flue gas, a portion of the sodium sulfite is oxidized to sodium sulfate. The bisulfite rich sodium-salt solution discharged from the absorber is thermally regenerated in a forced circulation evaporator. During the thermal regeneration of sodium bisulfite, SO_2 is liberated and sodium sulfite is reformed. The sulfur dioxide along with the equilibrium water vapor pass overhead through a series of parallel condensers where the

*Davy Powergas, Inc. P.O. Box 2436, Lakeland, Florida 33803.

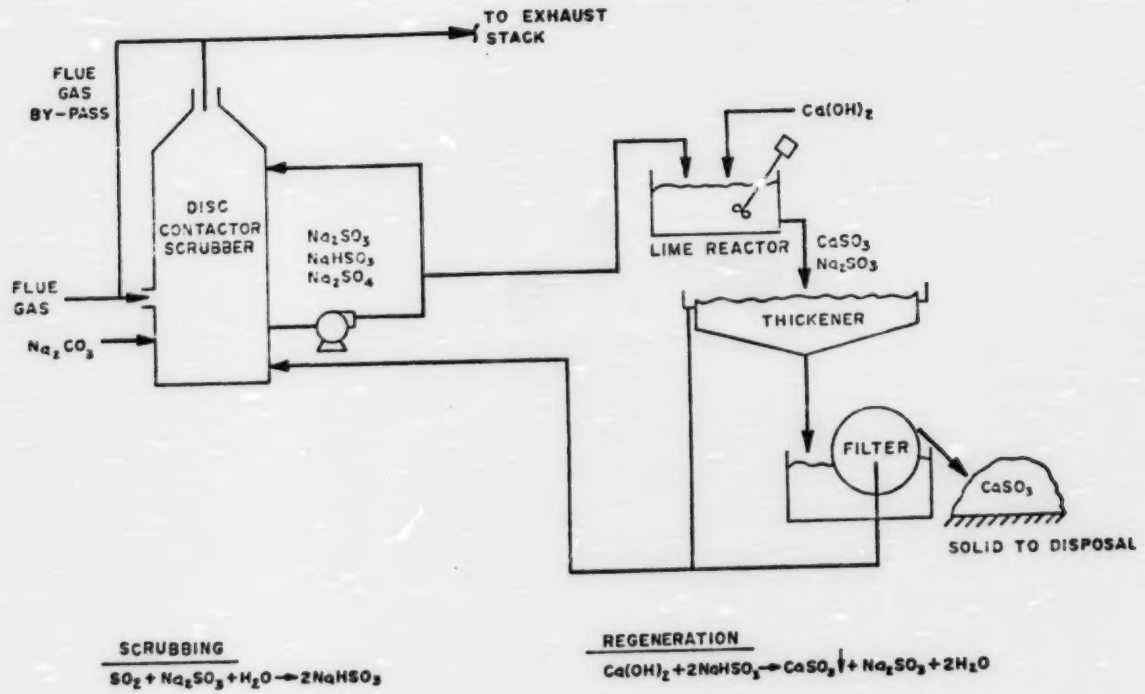


Figure 6. FMC double alkali scrubber system[14]

Table 7. FMC DOUBLE ALKALI SCRUBBING SYSTEM[15]

Smallest system capacity commercially available (scfm)	33,000
Overall pressure drop through system (in H_2O)	5 - 15
Turndown ratio of system	4:1
SO_2 removal efficiency, percent	90 - 95
Raw materials	Lime (CaO), soda ash (Na_2CO_3)
By-products	None
Wastes[a] lb waste/lb SO_2 removed	5.8 lb sludge cake from clarifier containing 35 percent solids ($CaSO_3$ and Na_2SO_4) and 65 percent water
Maintenance	This system is designed such that scaling is not a problem. Corrosion problems can be minimized with proper system design.
Development status	Operational systems 3 Mw; 2 % S coal; 90 % SO_2 removal 94 % availability; operating since 1/75 57 Mw; 3.2 % S coal; 90 % SO_2 removal 100 % availability; operating since 10/75 Systems in engineering design and construction phase of development 95 Mw; 3.2 % S coal; startup slated for 1977 93 Mw; 3.2 % S coal; startup slated for 1978

[a]Does not include the fly ash that would be removed.

desired level of SO_2 purity is achieved. The water condensate is returned to the process. Sulfur dioxide can be concentrated to greater than 95 percent. This recovered SO_2 can be converted to liquid SO_2 sulfuric acid or elemental sulfur.[19,20] For industrial size boilers, the economics of converting recovered SO_2 to sulfuric acid or elemental sulfur are unfavorable unless a plant already exists on the site. However, for industrial size boiler installations, production of liquid SO_2 appears to be a viable alternative.[21] To produce liquid SO_2, the SO_2 gas is first dried with silica gel. The dry SO_2 gas is then compressed and condensed. The liquid SO_2 is collected in a pressurized storage tank. A schematic diagram of the Wellman-Lord SO_2 recovery process is presented in Figure 7.[19] Table 8 presents pertinent design and operating data for the Wellman-Lord SO_2 recovery process.

By-Product Utilization and Disposal

Scrubbing systems for SO_2 control produce either sludges or sulfur based by-products that must be utilized or disposed. The utilization and disposal of sludges produced by lime and limestone scrubbing are emphasized in the following discussion, but waste streams from other processes are also considered. Regenerative SO_2 control systems produce by-products, sulfur, sulfur dioxide or sulfuric acid that may be sold at varying prices depending on available markets and the transportation costs. Liquid SO_2 has the highest unit value and its marketing would therefore be least affected by transport costs.

Sludges produced by lime and limestone SO_2 scrubbing systems contain primarily calcium sulfite, calcium sulfate, calcium carbonate and fly ash. Trace metals resulting primarily from coal ash components are also present in the sludge. Water content is typically 50 to 80 percent. An environmentally acceptable method for sludge disposal or utilization must be considered in the evaluation of the technical feasibility and cost of scrubbing. Numerous options have been proposed

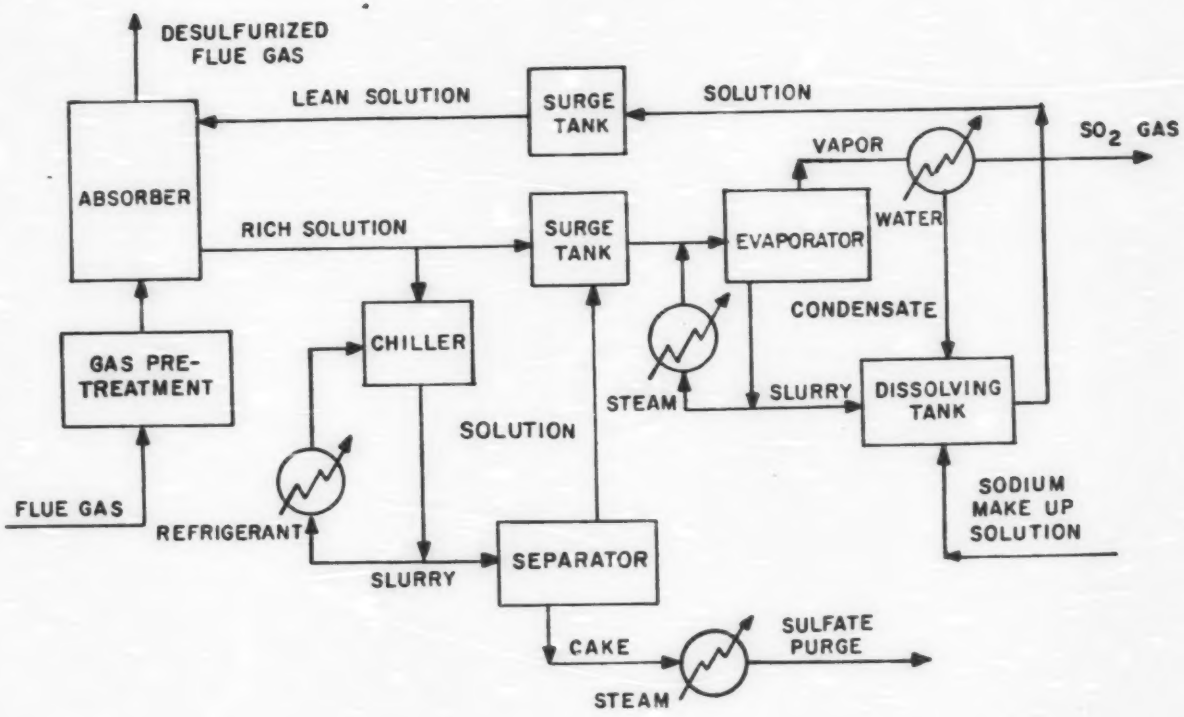


Figure 7. Wellman-Lord SO_2 recovery process

Table 8. WELLMAN-LORD SO_2 RECOVERY PROCESS

Smallest system capacity commercially available (scfm)	
Overall pressure drop through system (in H_2O)	30 - 40
Turndown	2:1
SO_2 removal efficiency, percent	90 - 99
Raw materials	Sodium hydroxide
By-products	Concentrated SO_2 which may be liquefied or converted to either elemental sulfur or sulfuric acid
Wastes[a] lb waste/lb SO_2 removal	0.5 lb sludge cake containing 35 percent solids (Na_2SO_4) and 65 percent water.
Maintenance	This system is designed such that scaling is not a problem. Corrosion problems can be minimized with proper system design.
Development status	System undergoing startup 115 Mw; 3.2 - 3.5 % S coal Systems under construction 375 Mw; 0.8 % S coal 340 Mw; 0.8 % S coal 500 Mw; 0.8 % S coal 500 Mw; 0.8 % S coal

[a]Does not include fly ash that would be removed.

for sludge utilization[22,23] but significant application of these techniques appears to be unlikely. A recent EPA sponsored study concluded that ponding and landfill are the only near term alternatives for sludge disposal.[24]

In order to assess this problem it is useful to compare the properties of scrubber sludge to fly ash. First, sludge tends to be more difficult to dewater either by settling or filtration and rewaters more easily. The platelet-like crystal structure of calcium sulfite hemihydrate ($CaSO_3$-1/2 H_2O) is believed to be primarily responsible for the high moisture retention.[25] Depending on the sludge composition including the amount of fly ash it will settle to 30 to 65 percent solids compared to fly ash which settles to 80 percent solids. Dewatering problems lead to increased processing costs, larger ponding areas and poorer landfill characteristics. Untreated sludge liquors have a lower pH than fly ash liquors thus causing greater trace metal solubility.[26] Wet scrubbing may also collect gaseous trace elements including chlorine and mercury, increasing the water pollution potential.

Many of the utilization alternatives would have to compete with fly ash. The limitation of these markets is illustrated by the point that only 8 percent of utility generated fly ash is currently utilized.[27] Potential uses include cement manufacture, gypsum board manufacture, production of light weight aggregates, road base, etc. One U.S. utility has noted that it may make economic and environmental sense to oxidize the sludge to gypsum ($CaSO_4.2H_2O$) even if the material has no current market value.[28] This material would be more easily dewatered, is not water soluble, and could be effectively compacted and landfilled. If market conditions improved, the gypsum could be recovered years later. For most of the potential applications sludge dewatering would be a problem. In addition, if sludge were utilized in a high temperature process such as cement manufacture, sulfur recovery would be required. Currently, lime/limestone scrubber sludges are either ponded or landfilled.

Ponding is currently the most commonly used lime/limestone sludge disposal method. All wet scrubbing systems present the potential problem of direct waste water discharge to surface waters. Eight full scale systems representing over 1500 Mw of boiler capacity have eliminated this problem by recirculating the scrubber liquor; i.e., closed loop operation.[29] Other installations recirculate as much of the liquor as technically feasible. Pollution of ground and surface waters from leachate formation is also a potential problem. Ponds may be lined with clay or synthetic materials like asphalt, PVC, Hypalon, etc.[30] The necessity for lining and/or stabilization depends on local regulations, sludge characteristics and local geology and hydrology. Currently, only Commonwealth Edison, Will County No. 1, is using a lined (clay) pond[8] but future requirements will probably be more stringent.

Costs for sludge disposal by ponding can vary very widely, depending on land cost; the type of liner used, if any; location of the pond in relation to the scrubbers; and the settling characteristics of the sludge. The need for a pond liner and the type used and therefore the disposal cost will depend on local geology, hydrology and environmental regulations. It has been suggested that the small size of some industrial boilers may reduce the sludge disposal problem as local environmental impacts will be reduced.[17] Aerospace Corporation has conducted a detailed evaluation of ponding[30] and is currently continuing programs in the area. Data from this initial study have been updated and cost ranges are $0.2-3 per ton of sludge (50 percent solids) for unlined pond disposal and $0.5-10 per ton of sludge for lined pond disposal.[24] The large range and higher upper limits reflect uncertainty in regard to unusual local situations. A cost of $3 per ton for sludge disposal in a lined pond was reported to be typical. Costs would be nearer $1 per ton if disposal in an unlined pond is allowed. Typical truck hauling rates for stabilized fly ash for a distance of 5 miles are reported to be $0.75/ton.[24] This may represent an added cost when offsite ponding or landfill is required. Based on the above data, GCA used a cost of $4/ton for sludge disposal.

Landfill is also a viable disposal method although use of this option is currently limited. Dewatering and sludge stabilization or chemical fixation are usually required for landfills. Chemical fixation and landfilling is reported to cost more than ponding in most situations, averaging about twice as much. A specific example of chemical fixation and landfill is the Bruce Mansfield No. 1 unit, a 835 Mw system. Projected costs are reported to be $7/ton of sludge including Dravo chemical fixation, acquisition and development of considerable land, and an 8-mile pipeline operation.[30] Fly ash and lime may be used to improve sludge quality. At Paddy's Run No. 6, 60 to 100 pounds of lime per ton dry solids are used to stabilize the sludge for trucking and offsite disposal.[8] Sludge from Will County No. 1 is stabilized by adding 200 lb lime and 400 lb fly ash per ton of dry solids.[8] A small industrial boiler might, depending on the local situation, be able to dispose of dewatered sludge cheaply in city or county operated sanitary landfills.

Sludges from sodium-based double alkali systems have been less intensively investigated. A major difference between sludges from lime/limestone systems and double alkali systems is that the former are primarily calcium sulfate ($CaSO_4$) while the latter are primarily calcium sulfite ($CaSO_3$). One might expect, in view of the dewatering problems attributed to minor amounts of $CaSO_3$ in lime/limestone sludge, that double alkali sludge would be difficult to dewater. However, FMC has investigated vacuum filtration and landfilling of double alkali sludge and reports success in both areas.[14] Perhaps the different conditions under which the sludges form also affects the properties.

While sludge disposal is an important environmental consideration , disposal methods are available and the annual cost should be relatively small, less than 10 percent of the total annual FGD cost.

LOW SULFUR COAL AND OTHER SO_2 EMISSION REDUCTION ALTERNATIVES

The use of low sulfur coal and/or mechanical coal cleaning are potential methods for complying with the proposed SO_2 regulations. These options will be particularly attractive in counties with the least stringent emission limitations. Coal gasification, coal liquefaction and fluidized bed combustion also appear to be applicable to industrial boilers, but will not be available until the 1980's. Therefore, these last three control methods cannot be considered for boilers in the present study, all of which must comply with the proposed regulation no later than 3 years after promulgation.

The sulfur content of coal needed to comply with the proposed regulations varies as the emission limit varies from 0.6 lb $SO_2/10^6$ Btu to 6.8 lbs $SO_2/10^6$ Btu in those counties that are regulated. Therefore, the sulfur content of "low sulfur" or compliance coal needed to comply with the proposed regulations will vary as shown in Table 9, assuming a heating value of 12,000 Btu/lb. The sulfur content of these compliance coals is higher than the 1 percent level defined as low sulfur coal in many studies. Large quantities of coal with sulfur contents in the required ranges are used by the industrial sector in Ohio. Coal shipments to Ohio industry, not including electric utilities and coke and gas plants, in 1972 totaled 12,700,000 tons of which 11 percent contained 1.1 to 1.3 percent sulfur, 6 percent contained 1.4 to 1.8 percent sulfur, 35 percent contained 1.9 to 3.0 percent sulfur and the remaining 48 percent contained above 3 percent sulfur.[31]

Coal supply district 4 (all of Ohio) provides 53 percent of industrial coal consumed in Ohio while district 8 (southern West Virginia, parts of Virginia, eastern Kentucky and northern Tennessee) provides 40 percent.[32] This industrial coal supply pattern is different from Ohio utility coal supply which consists of 64 percent district 4 coal, and only 15 percent district 8 coal. Therefore, it is evident that supply

Table 9. SO_2 EMISSION LIMITATIONS AND EQUIVALENT PERCENT SULFUR IN COAL[a]

lb $SO_2/10^6$ Btu	Percent sulfur in coal
0.6	0.36
1.0	0.60
1.5	0.90
2.0	1.2
2.5	1.5
3.0	1.8
4.0	2.4
5.0	3.0
6.0	3.6
6.8	4.1

[a]Based on a heating value of 12,000 Btu/lb and 100 percent conversion of fuel sulfur to SO_2.

and transport routes from district 8 are available to and utilized by Ohio industry. This is important because district 8 coal is commonly low in sulfur content and reserves of compliance coal are very large.

The reserve base of mineable coal in West Virginia, Kentucky and Ohio is presented in Table 10. These listed reserves include only measured and indicated coal seems greater than 28 inches thick and less than 1000 ft deep for deep mining and with less than 120 feet of overburden for strip mining. Reserves within these three states are large when compared to the 66 million tons/year currently used by all Ohio consumers. Perspective on the amount of reserves may also be gained by comparison of the current U.S. consumption of about 600 million tons/year to the West Virginia reserves of 40,000 million tons/total and 18,400 million tons of less than 1.5 percent sulfur coal. Even Ohio has significant reserves of coal that would comply with many of the regulations. A shift in consumption patterns by Ohio industry which uses about 12 million tons of coal per year should not affect coal supply and prices. However, a change in consumption patterns by Ohio utilities and neighboring states may affect coal prices. There may be

Table 10. BITUMINOUS COAL RESERVE BASE FOR SELECTED STATES, THICKNESS, TYPE OF MINING, AND SULFUR RANGE - JANUARY 1, 1974 (MILLION SHORT TONS)[33]

	RESERVES BY SULFUR RANGE, PERCENT											
Thickness	≤ 0.4	0.5 - 0.6	0.7 - 0.8	0.9 - 1.0	1.1 - 1.4	1.5 - 1.8	1.9 - 2.2	2.3 - 2.6	2.7 - 3.0	> 3.0	Unknown	Total
West Virginia												
Deep > 28	229.19	2923.45	4948.83	2985.13	3696.23	2615.11	2435.13	2057.71	1779.23	6552.88	4142.92	34377.77
Strip > 28	44.12	799.33	1363.37	798.64	581.16	262.61	239.14	191.94	147.97	270.40	509.55	5212.02
Total	273.31	3722.78	6312.20	3783.77	4277.39	2877.72	2674.27	2249.65	1927.20	6823.28	4652.47	39589.79
Kentucky												
Deep > 24	0.00	0.00	0.00	0.00	0.00	0.39	1.19	70.44	314.56	7226.36	1107.11	8719.89
Strip > 24	0.00	0.00	0.00	0.22	0.83	8.53	22.22	45.20	101.05	2017.45	1708.79	3904.02
Total	0.00	0.00	0.00	0.22	0.83	8.92	23.41	115.64	415.61	9243.81	2815.90	12623.91
Ohio												
Deep > 28	0.00	9.09	37.49	68.87	318.26	693.25	954.59	1414.95	2068.83	10109.36	1754.09	17423.26
Strip > 28	0.00	2.97	5.27	10.63	41.55	93.05	192.70	310.27	353.39	2524.87	117.93	3653.89
Total	0.00	12.06	42.76	79.50	359.81	786.30	1147.29	1725.22	2422.22	12634.23	1872.02	21077.15

delays in opening new mines and if demand for compliance coal out-paces the increase in supply, prices will certainly increase. These complicating factors make the prediction of future prices very uncertain.

Many Ohio industrial facilities obtain coal by spot purchases. Prices for spot purchases, FOB mine, as reported in Coal Week during 1975 indicate that district 8 coal with a sulfur content of 1.25 percent was less expensive than Ohio coal with an average sulfur content of 3.2 percent. In December 1975 Ohio spot purchased coal was $17.5/ton and district 8 coal was $14.25/ton.[34] In his testimony at the January 8, 1976 public hearing, A. L. Susman, Chairman, Mines and Mining Subcommittee, West Virgina Senate, reported several indications of a lack of demand for low sulfur coal and significant idle mines capable of producing less than 1 percent sulfur coal.[35] When switching from one coal to another, many coal properties including ash composition, ash fusion temperature, moisture content, etc. can affect boiler performance.[1,36] A suitable coal supply can only be determined on a case-by-case basis due to variations in the regulations and required fuel specifications. For the sites visited in this study GCA telephoned suppliers to determine current prices for coal with the required sulfur contents.

Mechanical coal cleaning has been widely used for many years and in 1973 about 50 percent of total coal consumption was cleaned coal.[37] Many of the systems now in operation, however, were designed primarily for ash removal. All coal used for coking (17 percent of total coal consumed and 33 of cleaned coal consumption) is cleaned to reduce both the sulfur and ash content. Coal cleaning technology is clearly commercially proven but its effectiveness depends on the properties of the specific coal being cleaned. A summary of the application of mechanical coal cleaning in 1973 is presented in Table 11. Most West Virginia coal is cleaned but much greater sulfur reduction could probably be achieved through process improvements. On the other hand,

less than half of Ohio coal production is cleaned and increased application of coal cleaning as well as improvement of existing systems could greatly reduce the sulfur and ash content.

Table 11. MECHANICAL CLEANING AT BITUMINOUS COAL AND LIGNITE MINES, IN 1973, BY STATE (THOUSAND SHORT TONS)[37]

State	Total production	Mechanical cleaning			
		Number of cleaning plants	Raw coal	Cleaned coal	Refuse
Alabama	19,230	19	18,433	11,705	6,728
Alaska	604	1	70	50	20
Colorado	6,212	3	1,933	1,662	270
Illinois	61,572	36	62,386	48,091	14,295
Indiana	25,253	10	25,330	19,699	5,631
Kentucky:					
Eastern	33,960	33	30,359	22,264	8,095
Western	53,679	18	26,004	20,005	5,999
Total	127,648	51	56,363	42,269	14,094
Ohio	45,783	17	20,799	14,588	6,211
Oklahoma	2,183	3	381	312	69
Pennsylvania	76,403	68	63,041	45,731	17,310
Tennessee	8,219	2	1,575	1,145	430
Utah	5,500	7	4,156	3,975	581
Virginia	33,961	32	26,559	17,696	8,863
Washington	3,270	2	4,460	3,262	1,198
West Virginia	115,448	124	107,520	75,672	31,848
Other States[a]	60,344	7	4,639	3,460	1,179
Grand total[b]	591,738	382	397,646	288,918	108,728

[a]Includes Arizona, Arkansas, Iowa, Kansas, Maryland, Missouri, Montana (bituminous coal and lignite), New Mexico, North Dakota (lignite), and Wyoming.

[b]Data may not add to totals shown because of independent rounding.

Mechanical coal cleaning separates coal constituents with different specific gravities, as shown in Table 12. Sulfur is present in coal both as pyritic sulfur, which can be separated, and organically bound sulfur which cannot be mechanically removed. The pyritic sulfur composes 20 to 80 percent of the total sulfur with the lower percentage usually found in lower sulfur coals.[26] Analyses of Ohio coals indicate that about half the sulfur is present as organic sulfur.[38] Crushing frees the pyritic sulfur particles from other coal particles and is the first step in mechanical cleaning. Coal is commonly crushed to less than 1-1/2 inches or less than 14 mesh and smaller in

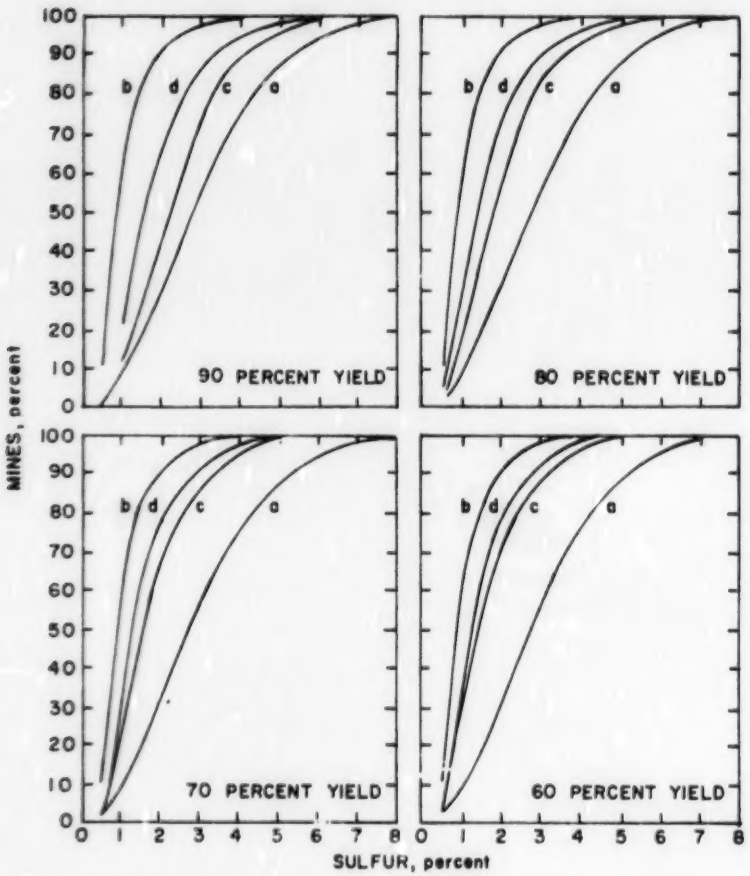
Table 12. SPECIFIC GRAVITIES OF COAL AND IMPURITIES

Material	Specific gravity
Bituminous coal	1.12 - 1.35
Bone coal	1.35 - 1.7
Carbonaceous shale	1.6 - 2.2
Shale	2.0 - 2.6
Clay	1.8 - 2.2
Pyrite	4.8 - 5.2

certain cases. The finer size produces better sulfur removal but the crushed coal is harder to handle and cleaning costs increase. Wet concentrating tables, compound water cyclones, air classification, froth flotation and concentrating spirals are widely used conventional commercially available methods for density separation in coal cleaning.[39] The net costs for mechanical coal cleaning are difficult to assess due to variations in coal washability. The Commerce Technical Advisory Board reported mid-1974 costs of $1.2 to $2.2/ton for crushing to 3/8 in. with single stage separation and $2.9 to $4.8/ton for a more elaborate multistage separation of finer particles.[40] Cost projections in Coal Age indicate a range of $6.5 to $9/ton to clean Appalachian coal to less than 1 percent sulfur.[41] An update by GCA fo cost data reported by Battelle,[17] indicates a current coal cleaning cost of $6/ton of product for removal of pyritic sulfur for the conditions used by Battelle.

Several cost benefits must be balanced against the coal cleaning costs. Coal cleaning reduces the ash content by 60 to 70 percent, and increases the heating content. Therefore, coal transport costs and ash handling and disposal costs are reduced. Boiler operation is potentially improved by reduced slagging, reduced need for particulate control, improved boiler availability and lower boiler operating and maintenance costs.[36] The Commerce Technical Advisory Board concluded that coal cleaning with or without additional FGD was the least expensive option for utility systems to meet the new source performance standard of 1.2 lb $SO_2/10^6$ Btu.[41]

Washability studies conducted on Northern Appalachian coals (Maryland, Ohio, Pennsylvania, Northern West Virginia) showed that coals from 20 percent of the mines could be washed to less than 1 percent sulfur and coal from 65 percent of the mines could be washed to less than 2 percent sulfur at a 90 percent yield when crushed to -14 mesh.[39] These results are summarized in Figure 8. The washed coals discussed above contained only 5 to 7 percent ash and had a heating value of about 13,000 Btu/lb.[39] Coals from the Northern Appalachian region are used extensively in Ohio. Washability studies were also conducted on Southern Appalachian coals, roughly equivalent to coal supply district 8, showing that samples from 90 percent of the mines could be reduced to less than 1 percent sulfur at a 90 percent yield when crushed to -14 mesh.[39]



(a) RAW COAL TOTAL SULFUR CONTENT CURVE;

(b) RAW COAL ORGANIC SULFUR CONTENT CURVE;

(c) WASHED COAL TOTAL SULFUR CONTENT COAL CURVE WHEN RAW COAL WAS CRUSHED TO MINUS 1 ½ INCHES; AND,

(d) WHEN RAW COAL WAS CRUSHED TO MINUS 14 MESH.

SOURCE: REFERENCE 39

Figure 8. Washability of northern Appalachian region coals

SECTION IV

SO_2 EMISSION REDUCTION COSTS

To obtain accurate control equipment costs, GCA asked four flue gas desulfurization system manufacturers to submit budgetary cost quotations. Pertinent boiler design and operating data along with site layout diagrams were included in GCA's request for cost estimates. Combustion Engineering, Davy Powergas, Research-Cottrell and FMC were the four flue gas desulfurization system manufacturers that were contacted. They all cooperated by providing the cost estimates that were requested. Two different desulfurization unit sizes were considered for PPG: (1) a large system to control all six stokers and both cyclones (total combined rated capacity of 2710×10^6 Btu/hr) operating at an annual load of 70 percent in order to both maintain normal plant operations and generate electric power which would be sold to a utility and (2) a smaller system to control one of the stokers and both cyclones (total combined rated capacity of 1420×10^6 Btu/hr) operating at an annual load of 85 percent in order to maintain normal plant operations.

For the four flue gas desulfurization systems considered in this study, the average annual control costs range from \$0.47 to \$0.56/10^6 Btu input for the large system and from \$0.50 to \$0.60/10^6 Btu input for the small system. Another SO_2 emission reduction alternative that was considered is the conversion to low sulfur coal. We estimate the additional annual fuel cost plus the average annual cost of a rail unloading facility to range from \$0.35 to \$0.48/10^6 Btu input for the large system and from \$0.45 to \$0.64/10^6 Btu input for tne small system with over 90 percent of the increased cost attributed to fuel.

While the costs presented in this report are the most up-to-date and accurate data available, they are still not complete engineering designs and may be subject to ultimate revision by the vendors. A system should not be selected as the most attractive process solely on the basis of the cost data presented in this report. When considering flue gas desulfurization, the demonstrated performance and reliability, the type of guarantee that can be obtained and various site-specific considerations such as raw materials, utilities, and solid waste disposal requirements must also be taken into account. By the same token, if low sulfur coal is chosen as an SO_2 emission reduction technique, long-term contracts with fuel suppliers, price stability, and guaranteed supply become important considerations.

UTILITY, MATERIAL, AND LABOR REQUIREMENTS FOR FLUE GAS DESULFURIZATION SYSTEMS

Detailed utility, material, and labor requirements based primarily on data furnished in equipment vendor estimates submitted to GCA are presented in Tables 13 and 14 for the 353,000 and 710,000 scfm flue gas desulfurization system sizes considered for this coal burning facility. The steam requirements of the Combustion Engineering desulfurization system are due solely to the use of steam heating coils for flue gas reheat. The Davy Powergas system uses steam primarily in the evaporator-crystalizer but also for flue gas reheat. By using flue gas bypass to reheat desulfurized stack gas, the Research-Cottrell and the FMC systems do not require steam. Because it uses an evaporator-crystalizer, the Davy Powergas system uses cooling water while none is required by the other system. Because it is a regenerative system which must minimize chemical losses, the Davy Powergas system has much lower process water requirements than the other three systems. We have assumed that both the labor and the materials required to maintain these desulfurization systems to each have an annual cost of between 3.5 and 4.5 percent of the fixed capital investment based on a TVA study.[42] Maintenance costs used

Table 13. UTILITY, MATERIAL, AND LABOR REQUIREMENTS FOR FLUE GAS DESULFURIZATION AT PPG BASED ON MAXIMUM RATED CAPACITY OF ALL BOILERS[a,9,10,15,21]

	Lime (C-E Power Systems)	Wellman-Lord (Davy Powergas)	Limestone (Research-Cottrell)	Double Alkali (FMC)
Utility				
Power, kWh/day	156,000	215,000	108,710	101,415
Steam, 1000 lb/day	782[b]	4,079[b]	0[c]	0[c]
Cooling water, 1000 gal/day	0	13,400	0	0
Process water, 1000 gal/day	1,062	19	447	695
Material				
Sodium hydroxide (NaOH), ton/day	0	26.5	0	0
Soda ash (Na_2CO_3), tons/day	0	0	0	11.4
Lime (CaO), ton/day	200	0	0	195.1
Limestone ($CaCO_3$), tons/day	0	0	504	0
Maintenance, percentage of fixed capital investment per year	3.5	4.5	3.5	3.5
Labor				
Operation	2	3.5	2	2
Maintenance, percentage of fixed capital investment per year	3.5	4.5	3.5	3.5

[a] Maximum rated capacity of 2710 x 10^6 Btu/hr heat input would only be achieved if PPG begins to sell electric power to a local utility. Chemical consumption is based on 4.3 percent sulfur coal, 11,200 Btu/lb, 710,000 scfm flue gas, and 86 percent SO_2 collection efficiency.

[b] 782,000 lb of steam/day for stack gas reheat based on C-E Power System estimate.

[c] Steam reheat is not used. Instead the scrubber efficiency is increased and 9 percent of the flue gas is bypassed.

Table 14. UTILITY, MATERIAL, AND LABOR REQUIREMENTS FOR FLUE GAS DESULFURIZATION AT PPG BASED ON MAXIMUM RATED CAPACITY OF TWO CYCLONE BOILERS AND ONE STOKER[a]

	Lime (C-E Power Systems)	Wellman-Lord (Davy Powergas)	Limestone (Research-Cottrell)	Double Alkali (FMC)
Utility				
Power, kWh/day	82,050	112,660[b]	56,960	53,140
Steam, 1000 lb/day	410[b]	2,137[b]	0[c]	0[c]
Cooling water, 1000 gal/day	0	7,021	0	0
Process water, 1000 gal/day	556	10	234	364
Material				
Sodium hydroxide (NaOH), ton/day	0	13.9	0	0
Soda ash (Na_2CO_3), ton/day	0	0	0	6.0
Lime (CaO), ton/day	104.8	0	0	102.2
Limestone ($CaCO_3$), ton/day	0	0	264.1	0
Maintenance, percentage of fixed capital investment per year	3.5	4.5	3.5	3.5
Labor				
Operation, men/shift	2	3.5	2	2
Maintenance, percentage of fixed capital investment per year	3.5	4.5	3.5	3.5

[a] This boiler capacity of 1420×10^6 Btu/hr is presently used to maintain normal plant operations. Flue gas volume is 353,000 scfm.

[b] 389,000 lb of steam for stack gas reheating based on C-E Power System estimate.

[c] Steam reheat is not used. Instead the scrubber efficiency is increased and 9 percent of the flue gas is bypassed.

in this study are on the high side of the probable range. Research-Cottrell based on operating experience at Cholla reports that costs should be less than half those used in this study. We estimate between 2 and 3.5 men per shift will be required to operate these systems, with the more complex Wellman-Lord system requiring 3.5 men per shift. Operator requirements were also adapted from a TVA study.[42]

UTILITY, MATERIAL, AND LABOR COSTS FOR FLUE GAS DESULFURIZATION SYSTEMS

Tables 15 and 16 present detailed FGD utility, material, and labor costs derived from the requirements noted in Tables 13 and 14. As shown in these tables, the total utility, material, and labor cost of the Davy Powergas system is the highest due to high maintenance requirements and steam consumption. The Research-Cottrell limestone system has the lowest gross utility, material, and labor cost of $3.6 million per year.

CAPITAL AND ANNUALIZED COSTS FOR FLUE GAS DESULFURIZATION

The capital and annualized costs as well as the individual components used to formulate these costs are presented in Tables 17 and 18. These costs are current to June 1976. The most important cost components, the installed cost of the battery limits plant, were based on up-to-date quotations furnished by the equipment manufacturers.[9,10,15,21] Other costs were derived from Tables 15 and 16 and an accounting technique derived from the utility financing method as modified by the Panhandle Eastern Pipeline Company.[17]

For the four large desulfurization systems, the cost of retrofit was estimated to be about 15 percent of the average capital cost of the installed battery limit plant above the normal site preparation requirements based on a report by Devitt, et al.[43] This cost of $2.4 million was also applied to the smaller system as extensive and similar ducting

Table 15. UTILITY, MATERIAL, AND LABOR COSTS FOR FLUE GAS DESULFURIZATION AT PPG BASED ON MAXIMUM RATED CAPACITY OF ALL BOILERS AND A 70 PERCENT YEARLY LOAD FACTOR, 10^3/YR

	Lime (C-E Power Systems)	Wellman-Lord (Davy Powergas)	Limestone (Research-Cottrell)	Double Alkali (FMC)
Utility				
Power, $0.02/kWh	800	1,099	556[b]	518[b]
Steam, $2/1000 lb	400[a]	2,085[a]	0	0
Cooling water, $0.06/1000 gal	0	205	0	0
Process water, $0.20/1000 gal	54	1	23	36
Total utilities	1,254	3,390	579	554
Material				
Sodium hydroxide (NaOH), $160/ton	0	1,083	0	0
Soda ash (Na_2CO_3), $75/ton	0	0	0	218
Lime (CaO), $40/ton	2,044	0	0	1,994
Limestone ($CaCO_3$), $12/ton	0	0	1,545	0
Maintenance	670	1,463	653	569
Total material	2,714	2,545	2,198	2,781
Labor				
Operation, $8/man-hour	140	245	140	140
Maintenance	670	1,463	653	569
Total labor	810	1,708	793	709
Total utility, material, and labor	4,778	7,644	3,570	4,044

[a] $400,000 is included for steam reheat of stack gases.

[b] Steam reheat is not used. Instead the scrubber efficiency is increased and 9 percent of the flue gas is bypassed.

Table 16. UTILITY, MATERIAL, AND LABOR COSTS FOR FLUE GAS DESULFURIZATION AT PPG BASED ON MAXIMUM RATED CAPACITY OF TWO CYCLONE BOILERS, ONE STOKER, AND AN 85-PERCENT YEARLY LOAD FACTOR 10^3/YR[a]

	Lime (C-E Power Systems)	Wellman-Lord (Davy Powergas)	Limestone (Research-Cottrell)	Double Alkali (FMC)
Utility				
Power, $0.02/kWh	509	699	354	330
Steam, $2/1000 lb	255[b]	1,327[b]	0[c]	0[c]
Cooling water, $0.06/1000 gal	0	130	0	0
Process water, $0.20/1000 gal	34	1	15	23
Total utilities	798	2,157	360	353
Material				
Sodium hydroxide (NaOH), $160/ton	0	689	0	0
Soda ash (Na_2CO_3), $75/ton	0	0	0	139
Lime (CaO), $40/ton	1,301	0	0	1,269
Limestone ($CaCO_3$), $12/ton	0	0	783	0
Maintenance	469	999	458	403
Total material	1,770	1,688	1,441	1,811
Labor				
Operation, $8/man-hour	140	245	140	140
Maintenance	469	999	458	403
Total labor	609	1,244	598	543
Total utility, material, and labor	3,177	5,089	2,408	2,707

[a]The boiler capacity is presently used to maintain normal plant operation.

[b]255,000 is included for steam reheat of stack gases.

[c]Steam reheat is not used. Instead the scrubber efficiency is increased and 9 percent of the flue gas is bypassed.

Table 17. CAPITAL AND ANNUAL COSTS FOR A 710,000 scfm FLUE GAS DESULFURIZATION SYSTEM AT PPG 10^3, JUNE 9,10,15,17,21,43,44

	Lime (C-E Power System)	Wellman-Lord (Davy Powergas)	Limestone (Research Cottrell)	Double Alkali (FMC)
Capital Requirement				
Battery limits plant installed (BLP)	---	25,095[a]	13,550[a]	11,550[a]
Site preparation and utilities, 20% of BLP[b]	---	5,020	2,710	2,310
Additional retrofit requirements	---	2,400	2,400	2,400
Fixed capital requirement	19,145[a]	32,515	18,660	16,260
Working capital,[c] 20% of gross operating cost	1,360	1,925	1,140	1,175
Total capital requirement	20,505	34,440	19,800	17,435
Annual Operating Cost				
Labor[d]	810	1,705	793	709
Administration and general overhead,[c] 60% of labor	486	1,025	476	425
Utilities[d]	1,254	3,390	579	554
Materials[d]	2,714	2,546	2,198	2,781
Local taxes and insurance,[c] 2.7% of capital requirement	517	878	504	439
Solid waste disposal, $4/ton	1,018	84	1,152	968
Gross operating cost	6,799	9,630	5,702	5,876
Sulfur dioxide byproduct,[e] credit $110/ton	0	-5,970	0	0
Total annual operating cost	6,799	3,660	5,702	5,876
Annualized Cost				
Annualized capital cost[f]	2,088	3,508	2,017	1,776
Federal income tax[c,g]	378	629	362	322
Total annual operating cost	6,799	3,660	5,702	5,876
Average annual cost	9,265	7,797	8,081	7,974
Average annual control cost, $/lb S removed	0.173	0.146	0.151	0.149
$/$10^6$ Btu coal consumed	0.557	0.469	0.486	0.480

[a] Manufacturer estimates, June 1976

[b] Normal site preparation; cost to bring utilities to the battery limit plant and connect raw flue gas ducts to BLP based on GCA review of similar costs reported in literature.

[c] Based on utility financing method as modified by the Panhandle Eastern Pipeline Company and described in Reference 17.

[d] See Table 15.

[e] Based on cost data presented in Reference 44.

[f] Total capital requirement is amortized over 20 years at a discount cash flow rate of 8 percent. This works out to an effective rate of 10.185 percent per year of the total capital requirement.

[g] Average Federal income tax = 1.731 percent of the sum of the total capital requirement and working capital.

Table 18. CAPITAL AND ANNUAL COSTS FOR A 353,000 scfm FLUE GAS DESULFURIZATION SYSTEM AT PPG 10^3, JUNE 1976[9,10,15,17,21,30,44]

	Lime (C-E Power System)	Wellman-Lord (Davy Powergas)	Limestone (Research-Cottrell)	Double Alkali (FMC)
Capital Requirement				
Battery limits plant installed (BLP)	---	16,510[a]	8,910[a]	7,600[a]
Site preparation and utilities, 20% of BLP[b]	---	3,300	1,780	1,520
Additional retrofit requirements	---	2,400	2,400	2,400
Fixed capital requirement	13,415[a]	22,210	13,090	11,520
Working capital,[c] 20% of gross operating cost	883	1,295	739	765
Total capital requirement	14,298	23,505	13,829	12,285
Annual Operating Cost				
Labor[d]	610	1,244	598	543
Administrative and general overhead,[c] 60% of labor	366	746	359	326
Utilities[d]	798	2,157	369	353
Materials[d]	1,770	1,688	1,441	1,811
Local taxes and insurance,[c] 2.7% of fixed capital requirement	362	600	353	311
Solid waste disposal, $4/ton	507	41	573	482
Gross operating cost	4,413	6,476	3,693	3,826
Sulfur dioxide byproduct,[e] credit $110/ton	0	-2,970	0	0
Total annual operating cost	4,413	3,506	3,693	3,826
Annualized Cost				
Annualized capital cost[f]	1,456	2,394	1,408	1,250
Federal income tax[c,g]	263	429	252	226
Total annual operating cost	4,413	3,506	3,693	3,826
Average annual cost	6,102	6,329	5,353	5,303
Average annual control cost, $/lb S removed	0.179	0.186	0.157	0.156
$/$10^6$ Btu coal consumed	0.577	0.599	0.506	0.502

[a] Based on manufacturer estimates in Table 17 scaled down to the proper size according to the gas flow ratios raised to the 0.6 power, June 1976.

[b] Normal site preparation; cost to bring utilities to the battery limit plant and connect raw flue gas ducts to BLP based on GCA review of similar costs reported in literature.

[c] Based on utility financing method as modified by the Panhandle Eastern Pipeline Company and described in Reference 17.

[d] See Table 16.

[e] Based on cost data presented in Reference 44.

[f] Total capital requirement is amortized over 20 years at a discount cash flow rate of 8 percent. This works out to an effective rate of 10.185 percent per year of the total capital requirements.

[g] Average Federal income tax = 1.731 percent of the sum of the total capital requirement and working capital.

would be required to provide the option of operating five stokers when a cyclone boiler is shut down. As discussed in an earlier section, solid waste disposal costs were estimated to be approximately $4/ton. A sulfur dioxide by-product credit of $110/ton based on data provided by Davy Powergas, was used.[44] As shown in Tables 17 and 18, the FMC desulfurization system had the lowest total capital cost while the Davy Powergas system, due to SO_2 by-product credits, had the lowest annual operating cost. Overall, annual desulfurization costs ranged from $7.8 to $9.3 million per year or $0.47 to $0.56 per 10^6 Btu fuel input for the 710,000 scfm system. The annualized costs for the smaller 353,000 scfm system ranged from $5.3 to $6.3 million per year or $0.50 to $0.60 per 10^6 Btu fuel input.

COST OF LOW SULFUR COAL UTILIZATION

Cyclone boilers operate as wet bottom (the bottom ash is a liquid) systems and require a low ash fusion temperature. As a result, these wet bottom units cannot tolerate coal that has an ash fusion temperature above 2550°F.[1] Since the spreader stokers at PPG handle dry bottom ash, coal ash fusion temperature does not present a problem. General Coal Company has available low sulfur coal with an ash fusion temperature between 2300 and 2400°F making it suitable for combustion in cyclone boilers. This coal is mined in Kentucky, contains 1.03 percent S, has a heating value of 13,000 Btu per pound, and costs between $35 and $40 per ton delivered.[45] Low sulfur West Virginia coals without this ash fusion temperature restriction, have a delivered cost ranging between $30.5 and $34 per ton. These coals have sulfur contents between 0.7 and 1 percent, have heating values between 12,300 and 12,500 Btu per pound and are marketed by the Island Creek and Princess Coal Companies.[46,47,48]

We have estimated the costs for two low sulfur coal consumption alternatives. For the first case we have assumed that when both cyclones and only one of the stokers are operating, they would all consume low fusion temperature coal in order to minimize coal storage and handling requirements. For the second case, when both cyclones and all six stokers are operating, we have calculated coal costs by assuming the six stokers will burn regular low sulfur coal and the two cyclones will combust low fusion temperature coal.

Due to the distances and quantities involved, rail transport of low sulfur coal would be required. For both the cases outlined above, the same rail unloading facility would be required. The capital cost of this facility would be about $2.5 million.[49]

Annualized cost for this capital investment, including federal income tax, local taxes and insurance, annualized capital costs, maintenance and utilities would be $416,000 based on the methods previously discussed in Tables 13 through 18. For the larger capacity case the total annual cost of low sulfur coal utilization would range from $0.35 to $0.48/$10^6$ Btu, with 93 to 95 percent of the cost attributable to the price of coal. For the smaller capacity case total costs of low sulfur coal utilization would range from $0.45 to $0.64/$10^6$ Btu with 91 to 94 percent of the cost attributable to the delivered coal price.

SECTION V

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